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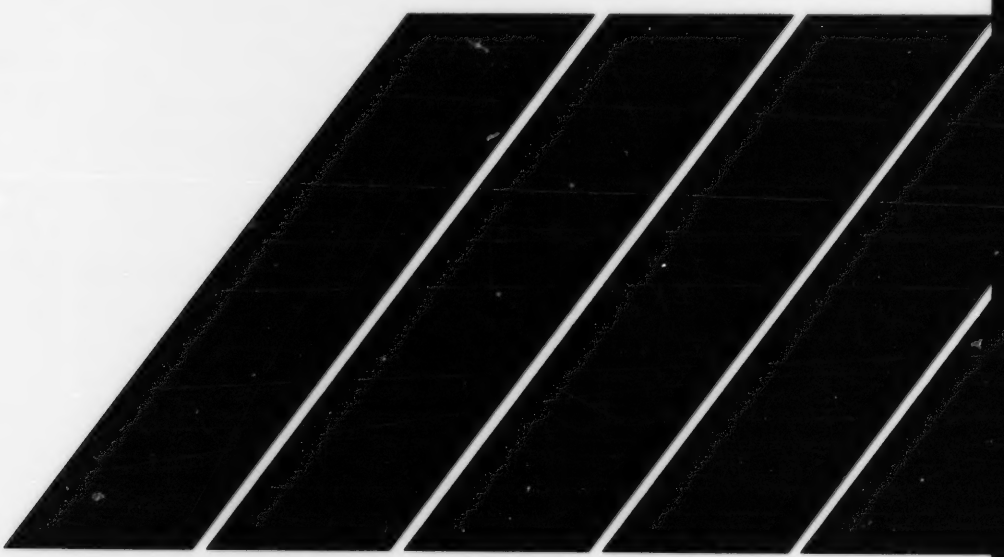
WOOD-WASTE-FUELLED, INDIRECTLY-FIRED GAS TURBINE COGENERATION PLANT FOR SAWMILL APPLICATIONS, PHASE III: PRELIMINARY ENGINEERING AND FINANCIAL ANALYSIS OF ALTERNATIVE CONFIGURATIONS



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WOOD-WASTE-FUELLED, INDIRECTLY-FIRED GAS TURBINE COGENERATION PLANT FOR SAWMILL APPLICATIONS, PHASE III: PRELIMINARY ENGINEERING AND FINANCIAL ANALYSIS OF ALTERNATIVE CONFIGURATIONS

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ABSTRACT

This report covers the third and final phase of an investigation into the feasibility of an innovative type of cogeneration system using an indirectly-fired gas turbine cycle. The general concept involves the use of an open Brayton-cycle gas turbine to generate electrical power, while process heat for the lumber dry-kilns is obtained by waste heat recovery from the turbine exhaust gas. During the first two phases of this project, preliminary engineering designs and financial analyses were provided for such a system at the generic and site-specific levels. In Phase III, the analysis was extended to cover three other configurations of the cogeneration system which use varying degrees of natural gas firing.

RÉSUMÉ

Ce rapport correspond à la troisième et dernière phase d'une enquête qui avait pour but de déterminer la faisabilité d'un type innovateur de système de cogénération fonctionnant à l'aide d'un cycle de turbine alimenté indirectement au gaz. Le concept général comporte la production de l'électricité à l'aide d'une turbine alimentée au gaz de type Brayton et le séchage de bois dans des fours alimentés par la récuperation des gaz d'échappement de la turbine. Lors des deux premières phases de ce projet préliminaire, les concepts d'ingénierie et les analyses financières étaient établis au niveau générique ainsi qu'au niveau spécifique à un site donné. Lors de la Phase III, L'analyse touchait également trois autres aspects du système de cogénération comprenant la combustion au gaz naturel.

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EXECUTIVE SUMMARY

INTRODUCTION

This report covers the third, and final, phase of an investigation into the feasibility of an innovative type of cogeneration system - "A Woodwaste-Fuelled, Indirectly-Fired Gas Turbine Cogeneration Plant for Sawmill Applications". The general concept, as illustrated in Figure 1, involves the use of an open cycle gas turbine as the prime mover to generate electrical power, while process heat for lumber dry-kilns is obtained by waste heat recovery from the turbine exhaust gas. A woodwaste-fired burner coupled with a high temperature air heater provides clean hot air to the gas turbine.

During Phase I, completed in February 1987, a generic design for a cogeneration system of this type was prepared for a typical sawmill producing 50 million board feet of lumber. The proposed system offered several major potential advantages over a conventional steam-based cogeneration system:

* reduced capital and maintenance costs;
* no requirement for full-time, licensed steam operators;
* no need for condenser cooling water.

Phase II of the project, completed in March 1988, advanced the generic design of Phase I by preparing a preliminary engineering design and financial analysis of the system at a specific sawmill site - the Boston Bar, B.C. mill operated by Fletcher Challenge Canada.

SCOPE OF PHASE III

During Phase III, the project team investigated a number of additional configurations of the cogeneration system which used varying degrees of natural gas co-firing. The use of natural gas to co-fire the turbine offers several potential advantages relative to an entirely wood-fired system:

1. Reduction of the size of the woodwaste combustor and heat exchanger;

2. Corresponding reductions in the capital cost of the system;

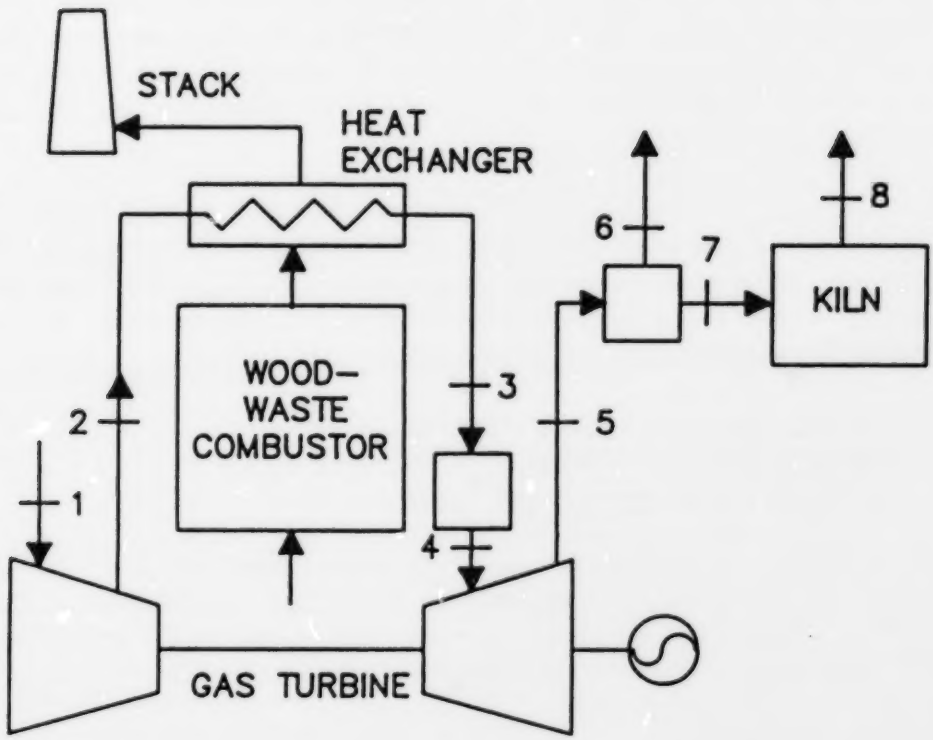

FIGURE 1: INDIRECTLY-FIRED GAS TURBINE COGENERATION SYSTEM*

* This simplified schematic drawing represents the one of four versions of the cogeneration system considered in Phase III of this project. During Phases I and II a number of variations on this system were explored, including different combustor/heat exchanger types and configurations, and the use of a hot oil system for kiln heating. See Appendix A for more detailed schematic drawings of the specific configurations considered during Phase III of the project.

3. Provision of a higher turbine inlet temperature than with wood firing, thereby avoiding derating of the electrical output;

4. Lowering the heat exchanger exit temperature to provide more reliable and longer-life operation.

5. The ability to continue operation during shut-downs of the woodwaste combustor or fuel handling system.

COGENERATION SYSTEM CONFIGURATIONS

Four alternative configurations of the gas turbine system were identified and examined in Phase III of the project. They range from wholly gas-fired to wholly woodwaste-fired, with two intermediate cases involving natural gas at approximately 27 and 50 percent of total fuel input to the system. Heat balances and schematic drawings were prepared for each of the four options examined.

The gas turbine chosen for all of the cases considered is the Kawasaki M1A-01. It is about the right size unit for a sawmill cogeneration system, with a full-load rated power output of 1122 kW. This is a simple single-shaft gas turbine with a two-stage radial compressor and three-stage axial turbine. An external combustion chamber is used which makes the unit ideally suited for conversion to an indirectly-fired cycle.

Case 1 -- Straight Gas-fired System

This system consists of the Kawasaki gas turbine unit complete with a natural gas combustion chamber, a control box which houses a damper system for directing exhaust gases into the dry-kiln, and the interconnecting ducting. For this case, operating strictly on natural gas, the full-load turbine inlet temperature of 900^{o}C is used, resulting in a turbine net electrical power output of 1122 kW. The gas-only case is by far the simplest, and has the lowest capital cost ($1.3 million) because of the absence of any provision for handling and firing woodwaste.

Case 2 -- Straight Woodwaste-Fired System

In this case all of the heat input to the turbine is obtained indirectly from a heat exchanger and woodwaste-fuelled combustor. The turbine inlet temperature is restricted to 760^{o}C at full-load conditions due to material considerations in the combustor and the heat exchanger. This limits the

gross electrical power output to 680 kW. Net power output is reduced to 530 kW, primarily due to the power requirements of auxiliary systems for the combustor forced-draft and induced-draft fans. The combustor would be a wet-cell type of hot gas generator which would produce combustion gases at a temperature between 1000 and 1100°C. The estimated capital cost of the Case 2 configuration is $3.1 million.

Case 3 -- 27 Percent Gas Co-fired System

This case is essentially the same as Case 2, but with the addition of natural gas co-firing to bring the turbine inlet temperature up to the full-load turbine rating of 900°C. This co-firing enables the turbine gross power output to return to the full-load rated value of 1122 kW, and also substantially increases the amount of exhaust gas heat available for kiln heating.

The combustor and heat exchanger design is identical to that for Case 2. Net power output is estimated at 972 kW, some 150 kW less than the power output for the straight gas-fired case (Case 1), due primarily to the requirement for auxiliary drives for both the forced-draft and the induced-draft fans. The capital cost of this system is also estimated at $3.1 million.

Case 4 -- 50 Percent Gas Co-Fired System

This case is the same as Case 3, except the quantity of natural gas used for co-firing with woodwaste has been increased to about 50 percent of the total energy input to the gas turbine. This results in a reduced heat input from the woodwaste combustor and a lower heated air outlet temperature from the heat exchanger. The lower air temperature reduces the technical risk in the heat exchanger design, along with the amount of heat exchange surface area required.

The gas turbine inlet temperature would be maintained at 900°C with the use of natural gas co-firing, so that the full-load turbine power output of 1122 kW would be achieved. As in Case 3, however, the net power output would be reduced to 972 kW, due to the auxiliary power requirements of the forced-draft and induced-draft fans. The $2.7 million capital cost for this alternative is substantially less than that for Case 3, given the much smaller combustor and heat exchanger.

FINANCIAL ANALYSIS

Projected capital and operating costs of the four cases considered are balanced against savings in purchased fuel and electricity costs in a financial feasibility model. This model calculates the after-tax internal rate of return and net present value of the project, and examines the sensitivity of these measures to changes in a number of variables, particularly relative natural gas and electricity prices and their future rates of escalation. The analysis examines the relative feasibility of four cases in the context of fuel and electricity prices to sawmills in both British Columbia and Ontario.

British Columbia

Given present electricity and natural gas prices in British Columbia, the system does not show a positive net present value or internal rate of return in any of the energy price escalation scenarios considered. If the power rate were increased to 5 cents per kWh, Case 1 (100 percent gas-fired) produces a quite attractive 32.5 percent rate of return, but the returns on other cases remain unacceptably low. While a woodwaste-disposal credit of $5 per oven-dried tonne would slightly improve the rates of return for the three cases which rely on woodwaste-firing to varying degrees, they would still remain much below the rate of return of the natural gas-fired system. Case 2 (100 percent woodwaste-fired) is clearly the least attractive of the options, yielding unacceptably low rates of return in all the sensitivity cases considered.

Ontario

With the higher natural gas prices that prevail in Ontario, Case 1 system yields lower financial returns than in B.C. if mills in both provinces are able to obtain 5 cents per kWh for their power. On the other hand, the other three cases, which have some degree of woodwaste firing, show improved returns relative to B.C., given the higher value of the natural gas which is displaced. In fact, Case 3 provides a slightly higher rate of return in Ontario than Case 1.

The $5/Odt woodwaste disposal credit is most beneficial to Case 2, given the greater amount displaced by this option. It still remains the least attractive of all the cases considered in the context of Ontario fuel and electricity prices.

Sensitivity to Natural Gas Price Increases

Many forecasting agencies have identified the potential for major increases in North American natural gas prices over the next decade. However, the financial analysis indicates that the results for the gas-fired cases are relatively insensitive to changes in rate of natural gas price escalation. In B.C., for example, the higher and lower gas price scenarios would change the rate of return by about 2.5 percent, even in Case 1 where natural gas is the sole fuel.

CONCLUSIONS

The analysis shows that at the scale of electrical generation considered, the configuration of the system that relies on straight wood-firing (Case 2) is the least attractive of the four cases. This results from the de-rated power and heat output relative to other cases considered, combined with high capital costs. Straight wood-fired cogeneration may still be valid, particularly at larger scales, but for the indirectly-fired gas turbine system considered herein, there are some potential technical, cost, and size problems with the high temperature heat exchanger which is the crucial component of the system.

Configurations of the system which are wholly or partially gas-fired have the potential to overcome these problems to varying degrees. Conclusions as to the relative merits of the cases which utilize some degree of natural gas firing vary among regions, depending upon relative natural gas and electricity prices.

1.0 INTRODUCTION

1.1 Background

This report covers the third, and final, phase of an investigation into the feasibility of an innovative type of cogeneration system - "A Woodwaste-Fuelled, Indirectly-Fired Gas Turbine Cogeneration Plant for Sawmill Applications". This system type was examined as an alternative to conventional steam/electricity (Rankine cycle) cogeneration systems which are not generally viable at the sawmill scale of operation. Research, design and development of the system, funded by the Bioenergy Development Program of the Diversity Energy Division of Energy, Mines and Resources Canada, has taken place in a number of phases.

In Phase I of this project, completed in February 1987, a number of alternative design concepts were reviewed before arriving at the indirectly-fired concept selected for preliminary engineering design and economic analysis. The general concept involves the use of an open Brayton-cycle gas turbine as the prime mover to generate electrical power, while process heat for lumber dry-kilns is obtained by waste heat recovery from the turbine exhaust gas.

During Phase I, a generic design for a cogeneration system of this type was prepared for a typical sawmill producing 50 million board feet of lumber. The proposed system offered several major potential advantages over a conventional steam-based cogeneration system:

* reduced capital and maintenance costs;
* no requirement for full-time licensed steam operators;
* no need for condenser cooling water.

The Phase I analysis indicated that the indirectly-fired gas turbine system might be both technically and financially feasible under a variety of conditions. On this basis the study team received funding from the Bioenergy Development Program to proceed with a second phase of the project.

Phase II of the project, completed in March 1988, advanced the generic design of Phase I by preparing a preliminary engineering design and financial analysis of the system at a specific sawmill site - the Boston Bar, B.C. mill operated by Fletcher Challenge Canada. Three different options, representing different scales and configurations of the system, were

considered during this phase of the project. The financial analysis indicated that, without substantial financial incentives, the demonstration-scale configuration (600 kW net output) of the system did not generate attractive rates of return, given the low electricity rates in British Columbia. Given the combination of a larger, commercial-scale configuration (1,800 kW) and higher power prices that exist outside of British Columbia, however, the analysis indicated potential for very attractive rates of return on the system investment.

1.2 Objectives of Phase III

The original goal of Phase III was to organize and structure a demonstration project for the type of system investigated in Phases I and II. In order to accomplish this general goal, Phase III was aimed at the following objectives:

1. Identify specific sites and industrial participants for which the system would be attractive.

2. Investigate and identify sources of funding for a demonstration project, including private, provincial, and federal sources.

3. Work with an engineering firm and equipment suppliers (turbine and heat exchanger manufacturers) to form a consortium which could engineer and build a system of this type.

4. Structure an agreement as the basis for proceeding with a project to demonstrate the technical and economic viability of the indirectly-fired gas turbine cogeneration system.

The project team expended considerable effort in seeking to secure the participation of sawmill operators, equipment suppliers, and engineering firms in such a demonstration. Unfortunately, conditions were not sufficiently favourable to attract participants for a demonstration project. In particular, natural gas prices in British Columbia have declined by 20 percent in nominal terms since the Phase II analysis, while electricity prices have remained the same in nominal dollars, indicating a decline in constant dollar terms for both natural gas and electricity. Similar pricing trends have prevailed in other major lumber-producing provinces.

At the same time, Federal and Provincial programs which might have co-funded a project of this type in the past have been terminated. Without

government co-funding, private companies are understandably reluctant to put up the large amount of money required for a commercial-scale demonstration, given the degree of technical risk involved relative to the limited potential rate of return under present circumstances.

The project team has therefore followed the suggestion of the Project Authority to investigate a number of additional configurations of the cogeneration system which use varying degrees of natural gas firing. The use of natural gas in co-firing the turbine offers several potential advantages relative to an entirely wood-fired system:

1. Reduction of the size of the woodwaste combustor and heat exchanger;

2. Corresponding reductions in the capital cost of the system;

3. Provision of a higher turbine inlet temperature than with wood firing, thereby avoiding derating of the electrical output;

4. Lowering the heat exchanger exit temperature to provide more reliable and longer-life operation.

5. The ability to continue operation during shut-downs of the woodwaste combustor or fuel handling system.

Although the use of a natural gas-fired turbine departs from the original concept of an indirectly-fired system, the presence of natural gas combustion products presents no problem in operation of dry-kilns.

1.3 Method

Four alternative configurations of the gas turbine system were identified. They range from wholly gas-fired to wholly woodwaste-fired, with two intermediate cases involving natural gas at approximately 27 and 50 percent of total fuel input to the system. The primary economic impact of gas firing or co-firing is to reduce capital costs, while increasing fuel-related operating costs.

Heat balances and schematic drawings were prepared for each of the four options examined. Projected capital and operating costs of the cases were then balanced against savings in purchased fuel and electricity costs in a financial feasibility model. This model calculates the after-tax internal rate of return and net present value of the project, and examines the sensitivity

of these measures to changes in a number of variables, particularly relative natural gas and electricity prices and their future rates of escalation.

Based upon this comparative analysis, a discussion is provided of the circumstances and applications in which the four alternative configurations of the cogeneration system would be viable.

2.0 ALTERNATIVE SYSTEM CONFIGURATIONS

2.1 Overview of Cogeneration Systems

The woodwaste-fuelled, indirectly-fired gas turbine cogeneration system examined in this Phase of the study is a simplified version of the system which was studied in detail in Phase II. In our earlier work the configuration included a hot-oil system to transfer heat to the dry-kiln. Taking into account discussions with sawmill operators and lumber kiln-drying experts, it was concluded that turbine exhaust gases could be fed directly to dry-kilns. The fact that there are many kiln-heating systems which use a simple gas-fired burner to provide kiln-heat confirms the viability of the approach. Potential loss of humidity control in feeding exhaust gases could be overcome by modifying drying schedules or injecting a small amount of moisture for humidity control. The main advantage of the modified configuration, in which the hot-oil system is eliminated, is a substantial reduction in overall capital cost.

Results of the Phase II study, together with feedback from sawmill operators, indicated that the economics of a straight woodwaste-fired unit would not be sufficiently positive to attract involvement of sawmills, given the degree of technical risk. Accordingly, an objective of this Phase of the project has been to identify more economic variations of the previously-envisioned system.

By incorporating the use of natural gas in the fuel supply, it was felt that the capital cost of the system could be substantially reduced. At the same time, the use of natural gas co-firing provides a higher turbine inlet temperature than straight woodwaste firing, avoiding derating of electrical output. In addition, the use of gas to boost turbine inlet temperatures allows the heat exchanger exit temperature to be lowered, reducing the degree of technical risk. Examination of natural gas-fired options was further supported, in the British Columbia context, by the considerable interest of B.C. Gas in gas-fired cogeneration, and by B.C. Hydro's increasing interest in soliciting power supply from independent producers.

Four alternative fuelling configurations were selected for examination in this Phase of the study. Two configurations, representing the extremes, would use straight gas firing without woodwaste in one case, and straight woodwaste firing without gas in the other. Two additional configurations represent intermediate cases. In the one instance, co-firing with natural gas is utilized to bring inlet temperature to the turbine up to the

manufacturer's suggested limit of 900°C, thereby obtaining the unit's full rated output. In the other case, in which the inlet temperature is also at 900°C, natural gas is used for about one-half the total energy input to the system. This option permits use of a smaller combustor and heat exchanger, thereby reducing capital cost relative to the first co-fired configuration.

The primary economic impact of gas firing or co-firing of the turbine cogeneration system is modification of the relationship between capital and operating costs. Lower capital costs, associated with gas-fired configurations, are subsequently offset to some degree by increased operating costs. Economic performance of the proposed systems is discussed in detail in Chapter 3.

2.2 Detailed System Descriptions

The gas turbine chosen for all of the cases considered here is the Kawasaki M1A-01. This is a simple, single-shaft gas turbine with a two-stage radial compressor and three-stage axial turbine. An external combustion chamber is used which makes the unit ideally suited for conversion to an indirectly-fired cycle. It is just about the right size unit for a sawmill cogeneration system, with a full load rated power output of 1122 kW. In addition, this turbine is readily available from a local distributor who has shown some interest in the project. For these reasons, the Kawasaki turbine has been used as the basis for this analysis rather than the Solar turbine upon which the Phase II analysis was based. The basic turbine data are shown in Table 2-1.

2.2.1 Case 1 -- Straight Gas-fired System

A schematic of the straight gas-fired cogeneration system is shown in Drawing No. A-1 in Appendix A. The system consists of the Kawasaki M1A-01 gas turbine unit complete with a natural gas combustion chamber, a control box which houses a damper system for directing exhaust gases into the drykiln, and the interconnecting ducting. The control dampers are used to enable some, or all, of the turbine exhaust gases to bypass the kiln if required. During some periods of operation no heat will be required, and so all of the exhaust gases will bypass the kiln, while at other times part of the gases will be bypassed to control the kiln temperature and relative humidity.

The heat balance data for this case are also shown on Drawing No. A-1. For this case, operating on natural gas, the full-load turbine inlet

temperature of 900°C is used, resulting in a turbine gross electrical power output of 1122 kW. The capital cost estimate for this case is shown in Table 2-2, which also indicates that the net electrical power output is 1122 kW. This is the same as the gross power output, since there are no auxiliary systems required, unlike the wood firing and co-firing cases considered. The gas-only case is by far the simplest, and has the lowest capital cost because of the absence of any provision for handling and firing woodwaste.

2.2.2 Case 2 — Straight Woodwaste-Fired System

A schematic of the straight woodwaste-fired cogeneration system is shown in Drawing No. A-2 in Appendix A. The system retains the Kawasaki M1A-01 gas turbine, but in this case all of the heat input to the turbine is obtained indirectly from a heat exchanger and woodwaste-fuelled combustor. As shown in the heat balance data, natural gas is not used for sustained operation, but only for start up of the system. In this case, the turbine inlet temperature is limited to 760°C at full-load conditions due to material considerations in the combustor and the heat exchanger. This temperature is estimated to be the maximum for reliable operation of components fabricated from conventional metallic materials (alloy 800 H); at significantly higher temperatures, exotic ceramic materials would be required. Because of the sensitivity of gas turbine power output to turbine inlet temperature, this limits the gross electrical power output to 680 kW. Net power output of this case, as shown in Table 2-2, is reduced to 530 kW, primarily due to the power requirements of auxiliary systems for the combustor forced-draft and induced-draft fans.

The combustor and heat exchanger design is assumed to be similar to that proposed in Option 1 of the Phase II study. The combustor would be a wet-cell type of hot gas generator which would produce combustion gases at a temperature between 1000 and 1100°C by controlling the amount of excess air provided by the forced-draft fan. The tubular air-heater would utilize tubes of alloy 800H material in the hottest section to withstand the sustained high temperatures, and a shell of steel platework. The design data for the Case 2 heat exchanger are given in Table 2-3.

Capital cost data for both the combustor and heat exchanger have been obtained by scaling the data used for Option 1 in Phase II, which was based on quotations. The capital costs for this case, shown in Table 2-2, are more than twice as much as those of the straight gas-fired system (Case 1), given the addition of the woodwaste fuel system and heat exchanger.

The same type of kiln bypass system as shown for Case 1 is used. This enables the turbine exhaust, which is pure air in this case, to be directed either entirely or partially into the kiln, or to bypass the kiln altogether. The kiln control system would adjust the bypass damper settings to obtain the appropriate temperature and humidity in the kiln for the lumber drying schedule chosen. It should be noted that because of the reduced kiln heat input of 3095 kW for this case (compared to approximately 4000 kW in other cases), as shown on Drawing No. A-1, a lesser quantity of dry-kiln natural gas would be displaced than in the other cases considered.

2.2.3 Case 3 -- 27 Percent Gas Co-fired System

This case, as shown schematically in Drawing No. A-3, is essentially the same as Case 2, but with the addition of natural gas co-firing to bring the turbine inlet temperature up to the full load turbine rating of 900^{o}C. This co-firing is beneficial to the system performance in two ways. It enables the turbine gross power output to return to the full-load rated value of 1122 kW, and it also substantially increases the amount of exhaust gas heat available for kiln heating.

The quantity of gas used for co-firing is approximately 150 cubic meters per hour, or about 27 percent of the total energy input to the gas turbine. The combustor and heat exchanger design for Case 3 is identical to that of Case 2, as shown in Table 2-3. The capital cost for this configuration is therefore also the same as for Case 2, as detailed in Table 2-2 which also shows that the net power output would be 972 kW. This is some 150 kW less than the power output for the straight gas-fired case (Case 1), again largely due to the requirement for auxiliary drives for both the forced-draft and the induced-draft fans.

2.2.4 Case 4 -- 50 Percent Gas Co-Fired System

This case is the same as Case 3, except the quantity of natural gas used for co-firing with woodwaste has been increased to about 50 percent of the total energy input to the gas turbine. This results in a reduced heat input from the woodwaste combustor and a lower heated air outlet temperature from the heat exchanger. The heat balance data for this configuration under full-load conditions are shown on Drawing No. A-4. The lower heat exchanger exit temperature of 620^{o}C offers the potential for longer and more reliable heat exchanger operation, reducing the technical risk in the heat exchanger design. It also would result in a substantial reduction in the heat exchange surface area required, which could be a significant

benefit in many sawmills which have only limited site area available.. The design data for the heat exchanger for this case are shown in Table 2-3.

The gas turbine inlet temperature would be maintained at 900^{o}C with the use of natural gas co-firing so that the full-load turbine power output of 1122 kW would be achieved. As in Case 3, however, the net power output would be reduced to 972 kW, due to the auxiliary power requirements of the forced-draft and induced-draft fans. The capital cost for this alternative, shown in Table 2-2, is substantially less than that for Case 3. This is due to the fact that a much smaller combustor and heat exchanger can be used, as gas accounts for a greater proportion of the total energy input.

2.3 System Design Summary

A summary of the four cases considered is shown in Table 2-4. Respectively, cases 1 and 2 represent 100 percent gas firing and 100 percent woodwaste firing. The 100 percent gas-fired case has by far the lowest capital cost, but it has the highest gas consumption and therefore highest fuel cost. This case does not, however, utilize any of the available woodwaste and so does not contribute to the waste disposal problem. On the other hand, Case 2 utilizes only woodwaste as a fuel, except for start-up, and therefore has the lowest fuel cost, but the highest capital cost. This case also provides the lowest electrical power output, due to the reduced turbine inlet temperature.

Cases 3 and 4 are intermediate cases relative to Cases 1 and 2. They utilize woodwaste, but also include co-firing with natural gas. The principal advantage of gas co-firing is that the full-load turbine inlet temperature of 900^{o}C is achieved, resulting in a substantial increase in power output compared to the straight woodwaste- fired case.

TABLE 2-1

KAWASAKI M1A-01 TURBINE DATA

Pressure Ratio	8:1
Air Mass-Flow	7.7 kg/s
Turbine Inlet Temperature	900^{O} C
Compressor Efficiency *	78%
Turbine Efficiency *	83%
Net Power Output	1122 kW

* Calculated Data

TABLE 2-2

CAPITAL COST ESTIMATES

FOR ALTERNATIVE CONFIGURATIONS OF COGENERATION SYSTEM

('000 $)

	CASE 1	CASE 2	CASE 3	CASE 4
Fuel:	100% Gas	100% Wood	27% Gas	50% Gas
Net Electrical Output, kW:	1122	530	972	972
Fuel Handling System				
Fuel transfer to storage and Pneumatic delivery system	0	150	150	150
Fuel Surge Bin	0	25	25	25
Subtotal	0	175	175	175
Cogeneration System				
Combustor	0	350	350	240
Heat Exchanger	0	500	500	275
I.D. Fans	0	25	25	20
Multi-clones	0	45	45	35
Gas Turbine/Generator	900	900	900	900
Stack	10	60	60	60
Ducting	35	35	35	35
Control Dampers	15	15	15	15
Electrical & Instrumental	50	200	200	200
Civil/Structural	50	100	100	100
Installation and Insulation	50	200	200	200
Engineering & Project Mgmt.	75	185	185	160
Contingency	125	280	280	240
TOTAL	1310	3070	3070	2655

TABLE 2-3

HEAT EXCHANGER DESIGN DATA
FOR ALTERNATIVE CONFIGURATIONS OF COGENERATION SYSTEM

	CASES 2 & 3	CASE 4
Hot Gas Inlet Temperature	1010° C	1010° C
Hot Gas Outlet Temperature	588° C	588° C
Cold Air Inlet Temperature	308° C	308° C
Heated Air Outlet Temperature	760° C	620° C
Heat Exchange Surface Area	411 m^2	223 m^2
Effectiveness	64%	44%
Capital Cost	$507,000	$275,000

TABLE 2-4

TECHNICAL AND CAPITAL COST SUMMARY
FOR ALTERNATIVE CONFIGURATIONS OF COGENERATION SYSTEM

	CASE 1	CASE 2	CASE 3	CASE 4
Turbine Inlet Temperature	900° C	760° C	900° C	900° C
Electrical Power kW				
Gross	1122	680	1122	1122
Net	1122	530	972	972
Gas Requirement m^3/hr	554	---	150	278
Waste Heat kW	4000	3100	4000	4000
Capital Costs ('000 $)				
Combustor	---	352	352	240
Heat Exchanger	---	507	507	275
Turbine	900	900	900	900
TOTAL	1,310	3,070	3,070	2,655

3.0 FINANCIAL ANALYSIS

3.1 Context for the Analysis

Based upon estimated capital and operating costs for the four configurations (Cases 1 through 4) of the cogeneration system detailed in the foregoing section, this section analyzes the financial feasibility of the system under a variety of conditions. It should be stressed that the main purpose of this financial analysis is to provide an indication of the relative viability of the four cases considered. The engineering and operating cost estimates are at the pre-feasibility level of accuracy, while the relatively small scale of the cases considered (530 to 1122 kW net electrical output) undoubtedly would provide less attractive returns than larger-scale units, as demonstrated in the Phase II study.

3.2 Financial Analysis Assumptions

In order to analyze the financial feasibility of the four cases considered, assumptions must be made concerning a number of key variables. These include:

- relative capital and operating costs for each case;
- the quantities of fuel and electricity displaced;
- the cost of fuel and electricity displaced;
- future rates of energy price escalation;
- debt/equity ratio;
- loan rate and amortization term;
- general inflation rate;
- discount rate for determining net present value.

To facilitate analysis of the sensitivity of the cogeneration system to changes in these variables, a computer model incorporating all of these factors was developed to calculate the after-tax internal rate of return and net present value.

Key assumptions concerning these variables are discussed separately below.

3.2.1 Relative Capital and Operating Costs

Capital costs for each of the four cases considered were specified in detail in Section 2.0. These are summarized in Table 3-1, along with

TABLE 3-1: FINANCIAL ANALYSIS ASSUMPTIONS FOR ALTERNATIVE CASES

CAPITAL AND OPERATING COSTS	CASE 1 100 % gas	CASE 2 100 % woodwaste	CASE 3 27 % gas	CASE 4 50 % gas
Capital cost	$1,310,000	$3,070,000	$3,070,000	$2,655,000
Operating Costs:				
Maintenance	$32,750	$76,750	$76,750	$66,375
Operating labour	$10,000	$40,000	$40,000	$40,000
Insurance and property taxes	$32,750	$76,750	$76,750	$66,375
Total Operating Costs	$75,500	$193,500	$193,500	$172,750

FUEL AND ELECTRICITY BALANCES		CASE 1 100 % gas	CASE 2 100 % woodwaste	CASE 3 27 % gas	CASE 4 50 % gas
Woodwaste consumed	(Odt)	0	13,000	9,490	6,500
Dry kiln gas displaced	(GJ)	115,200	89,600	115,200	115,200
Turbine fuel gas	(GJ)	155,120	0	42,000	77,840
Net gas use decrease	(GJ)	(39,920)	89,600	73,200	37,360
Electricity generated:					
Energy (MWh)		8,976	4,240	7,776	7,776
Demand (kW)		1,122	530	972	972

Odt = Oven-dried tonne

Electrical energy generated based upon 8,000 hours per annum.

corresponding operating cost estimates. Maintenance and insurance/property taxes are each estimated at 2.5 percent of the capital cost in all cases. Operating labour for Case 1, the wholly gas-fired system, is estimated at $10,000 annually, versus $40,000 for the other three cases which rely partially or entirely on wood-fired systems which require much more attention than a straight gas-fired system. These costs are considered incremental to current operating costs of the relevant mill and kiln facilities.

3.2.2 Quantities of Fuel and Electricity Displaced

The analysis is based on the assumption that the system will produce electricity and by-product heat for 8000 hours per annum. This equates to a load factor of about 91 percent. Most sawmills generally cut lumber for 480 or, at most, 720 shifts per year, but will run their dry-kilns most of the time. In this analysis, it is assumed that all of the waste heat from the turbine (a maximum of 120 terajoules per annum in Case 1) can be used to displace natural gas that was previously purchased for this purpose. This is probably reasonable, since a typical Interior B.C. sawmill producing 100 million board feet of kiln-dried lumber annually will consume about 160 terajoules of natural gas annually.

In a sawmill of the above scale, the dry-kilns alone are not sufficient to consume all of the electric power output in any of the cases considered. However, with the opportunity for independent power producers in B.C., Ontario, and other provinces to sell their surplus output to the electric utilities, it is not unreasonable to expect that all of the electrical output from the cogeneration plant could either be sold or used to displace formerly-purchased power.

The quantities of fuels and electricity assumed to be displaced in each of the four cases considered are summarized in Table 3-1.

3.2.3 Energy Prices

Of all the input variables in the financial analysis model, energy prices probably have the most potential for variation, not only in terms of their future rate of escalation over the longer term, but also in terms of variation in present relative energy prices among different geographical areas. For this reason, the sensitivity of financial feasibility measures to different base year natural gas and electricity prices has been examined, along with the impact of various rates of energy price escalation.

The forecast natural gas and electricity prices adopted herein are intended to represent prices to large sawmills in British Columbia in one scenario, and to mills in Ontario in the other. Utility buy-back prices and policies pertaining to independent power producers in these provinces have also been examined.

Electricity Prices

The current (November 15, 1989) B.C. Hydro tariff applicable to most sawmills (General Service, 35 kW and over) consists of the following trailing components:

Demand charge $6.19/kW demand/month
Energy charge 2.72 cents per kWh

A combined energy and demand rate of 3.65 cents per kWh has been used to represent the savings in electricity costs attainable from cogeneration, based upon the assumption that the displaced power has the same load factor as the cogeneration system (91 percent).

B.C. Hydro will also buy power from independent power producers (IPP's), but under present policies, only at a flat rate of 3 cents per kWh from plants of less than 5 MW. For larger generators, it will purchase power on a competitive proposal call basis, provided that the bids are less than the utility's avoided marginal cost. B.C. Hydro's stated levelized ceiling price for a 20-year contract starting in 1993/94 is 4.0 cents per kWh ($1989).

Recently, however, the utility was authorized by the Province to pay a premium of up to 15 percent above its avoided marginal cost for electricity generated by environmentally beneficial power projects (Special Direction #2 to the B.C. Utilities Commission). While not specifically restricted to woodwaste-fired power plants, the guidelines for implementing this policy note that "priority will be given to electricity generated from waste products whose disposal has resulted in local environmental damage". Unfortunately this policy is of limited value to producers of less than 5 MW, as they can still obtain a much higher rate per kWh by displacing formerly purchased power.

The same effect might be more equitably achieved if participating sawmills were subjected to a "tipping fee" equal to their avoided cost should they be required to meet the same emission standards which will be achieved by the cogeneration plant (i.e., emissions control costs would be transferred from the consumers of electricity to producers of the waste stream).

Ontario Hydro, on the other hand, will pay IPP's of less than 5 MW a rate of 3.97 cents per kWh, escalatable at the consumer price index, or a flat rate of 4.94 cents per kWh for 10 years without any escalation. It should be noted, however, that these rates are only applicable to plants which primarily rely on renewable energy sources. A similar restriction exists in Alberta where it has recently been recommended that the Small Power Research and Development Program guarantee a flat rate of 5.2 cents/kWh until 1995, at which time it will increase to 6.0 cents/kWh. Alternatively, the small power producer may select a price of 4.64 cents/kWh starting in 1990, escalating with inflation.

Based upon 1990 Ontario Hydro General Service rates which would be applicable to sawmills of the scale considered in the Phase II report (100 million board feet per year), an Ontario sawmill could save about 5 cents per kWh in combined energy and demand charges by displacing purchased power with self-generated electricity.

In both B.C. and Ontario, therefore, sawmills of this scale would obtain a larger benefit from displacing utility-generated power than selling power to the utility. Hence, the present purchased power rates of 3.65 and 5 cents per kWh are used as base year electricity prices in the financial analysis to represent British Columbia and Ontario, respectively.

B.C. Hydro projects nominal rate increases of 3 percent per annum until 1997. In the context of a 4.5 percent annual inflation rate, the real cost of power would decline by 1.5 percent per annum. By the year 2000, however, the real cost of power is expected to rise to about 5.0 cents/kwh. Ontario Hydro's most recent load forecast is also reportedly based upon the assumption that power rates will remain constant in real terms over the longer term. **Over the forecast period, the simplifying assumption has been made that electricity rates in both provinces will remain constant in real terms.**

In the short term, the factor which has the most potential to influence the viability of cogeneration is the impact of a fundamental change in rate design. In Volume I of its 1989 rate application to the British Columbia Utilities Commission, B.C. Hydro states that:

"To further encourage efficiency, it will be necessary to alter the current tariff structure so that the average charge per kWh does not decrease as the consumption increases. This might be accomplished by setting a relatively low rate for a minimum level of consumption, and then raising the

rate toward replacement cost for consumption above that level. While such restructuring would improve efficiency by giving a more accurate signal of the cost of increasing consumption, it would also raise significant issues about fairness and equity within and across rate classes. Preliminary analysis is underway on the issues, and B.C. Hydro intends to file a separate rate application for tariff restructuring late in 1990."

If this type of rate structure were to produce the same total revenue within the General Service rate class, it could encourage cogeneration by increasing rates for the trailing blocks of power which would be the first to be displaced by self-generation. In the event that the trailing block rate were even increased to the present average rate, the impact would be significant - for the scale of mill considered in the Phase II report, the combined energy and demand charge per kWh would increase by almost 18 percent from the present trailing energy and demand rates. In order to represent the impact of this type of tariff restructuring, the current Ontario price level of about 5 cents per kWh has been used as the B.C. electricity price in one of the sensitivity cases considered. This price level also represents the longer-term (year 2000) marginal cost of electricity in British Columbia.

Natural gas prices

Sawmills in the Interior of B.C. are reportedly able to purchase natural gas for $2.75 to $3.00/GJ on a direct sale basis. The corresponding price for northwestern Ontario mills is estimated to be about $3.75/GJ.

While there is general agreement that gas prices are unlikely to drop further in real terms, expectations vary widely as to the future rate and timing of gas price escalation. Estimates of the potential increase in constant 1989 dollar wellhead prices over the next 10 years range from zero to more than $3/GJ. The actual magnitude of the increase will, of course, depend upon a number of key technical, economic, and policy factors, most of which are difficult to predict with any precision over a 10-year forecast horizon. Some of the key factors are as follows:

1. Construction of additional pipeline capacity to key U.S. gas markets will allow additional quantities of Canadian natural gas to be exported;

2. Future emissions standards may favour the substitution of natural gas or natural gas-based fuels for other fuels;

3. Supply and demand elasticity responses to future natural gas price increases.

The first two factors are expected to exert upward pressures on domestic natural gas prices. However, over the past two decades it has been clearly demonstrated that there is considerable elasticity in both the supply of and demand for energy commodities. There may be a lag of several years before new supplies or substitutes are brought on-stream, or before energy conservation measures are implemented, but these responses will occur in a significant way if much higher prices prevail.

Major increases in the wellhead price have the potential to elicit considerable incremental natural gas supply, both in Canada and the U.S. At the same time, substitution of heavy fuel oil and woodwastes in the industrial sector, and conservation in all sectors will reduce the demand. A sharp gas wellhead price increase of 1 or 2 dollars/GJ (constant 1989 dollars) over the next several years could produce another "gas bubble" that would soon depress gas prices for a number of years.

After reviewing a number of natural gas price forecasts by various agencies, the following cases were considered:

	Low	Base	High
		($1989 Can./GJ)	
Wellhead price increase 1990 - 2000	$0.00	$1.00	$2.00
Delivered B.C. sawmill price Year 2000	$2.75	$3.75	$4.75

The base and high price scenarios would require average real price increases of 3.15 and 5.62 percent annually to B.C. sawmills, although in reality, it is unlikely that there will be a smooth, progressive price increase over the next ten years. Lacking more precise knowledge at to the timing of future price increases, natural gas prices have been assumed to grow in this fashion.

For Ontario mills, the same wellhead price increases have been applied, resulting in sawmill plant-gate prices of $4.75 and $5.75/GJ in the base

and high price scenarios, respectively, by the year 2000. With the higher base year gas price in Ontario, the percentage increases over the forecast period are lower than in B.C.

3.2.3 Other Financial Assumptions

The following conditions are used as a basis for project financing:

- 60/40 percent debt/equity ratio;
- 10-year term for loan amortization;
- 10-year period for financial analysis;
- 11 percent interest rate;
- corporate tax rate of 46 percent;
- 3-year depreciation (25 %, 50 %. 25 %);
- 5 percent general inflation rate;
- 8 percent real discount rate (13.4 % nominal).

The latter factor is applied to all parameters expect the loan term and energy prices. This project qualifies for an accelerated depreciation allowance (25 %, 50 %, 25 % over 3 years) under Class 34 of the Capital Cost Allowance system, which includes equipment used for the generation of electricity, or the production or distribution of heat. It is assumed that operators would be in a position to take full advantage of this allowance.

3.3 Financial Analysis Results

Based upon the foregoing assumptions, the financial results for the main cases considered are summarized in Table 3-2. In addition to these cases, a number of other scenarios were analyzed, as discussed in the following text.

3.3.1 British Columbia

Given present electricity and natural gas prices in B.C., the system does not show a positive net present value or internal rate of return in any of the cases considered. If the power rate were increased to 5 cents per kWh, Case 1 (100 percent gas) produces a quite attractive 32.5 percent rate of return. Only relatively low rates of return are indicated in Cases 3 and 4, however, with Case 2 (100 percent woodwaste) negative in terms of both financial measures.

TABLE 3-2: FINANCIAL ANALYSIS RESULTS FOR ALTERNATIVE CASES

B.C. With Present Gas Price and Higher Electricity Price:

Natural gas $2.75/GJ
Electricity $0.05/kWh

	Woodwaste Disposal Credit $/Odt	CASE 1 100% gas	CASE 2 100% wood waste	CASE 3 27% gas	CASE 4 50% gas
IRR	0	32.5%	-6.2%	17.4%	12.2%
IRR	5	32.5%	9.6%	22.4%	17.1%
NPV	0	$279,682	($332,328)	$118,904	($25,942)
NPV	5	$279,682	($96,805)	$290,837	$91,820

Ontario With Base Year Natural Gas and Electricity Prices

Natural gas $3.75/GJ
Electricity $0.05/kWh

	Woodwaste Disposal Credit $/Odt	CASE 1 100% gas	CASE 2 100% wood waste	CASE 3 27% gas	CASE 4 50% gas
IRR	0	24.0%	13.2%	24.8%	17.8%
IRR	5	24.0%	20.6%	28.9%	21.8%
NPV	0	$134,115	($5,605)	$385,826	$110,290
NPV	5	$134,115	$229,919	$557,758	$228,052

NOTES:

1. Natural gas prices are escalated at base case rate, while electricity prices are held constant in real terms.
2. IRR (Internal rate of return) of in context of 5 percent inflation rate.
3. NPV (Net present value) based upon 8 percent real discount rate (13.4 percent nominal).

If a mill were able to reduce its woodwaste disposal costs through operation of the wood-fired system configurations, financial returns could be somewhat enhanced. Woodwaste disposal costs are very site-specific, depending upon the present method of disposal and prevailing environmental standards. A conservative estimate of disposal costs through incineration is at least $5 per Odt (oven-dried tonne), taking into account both capital and operating costs. With the prospect of increasingly stringent environmental standards in the future, such costs are very likely to increase in real terms. However, unless the mill can dispose of all of its woodwaste in the burner of the cogeneration system, it may still need to operate an on-site burner.

In any event, a woodwaste disposal credit of $5/Odt would improve the rate of return by about 5 percent in the B.C. case represented in Table 3-2. The straight natural gas-fired system (Case 1), however, still is shown to provide a much higher rate of return than the other three options which rely on wood firing to varying degrees.

3.3.2 Ontario

With the higher natural gas prices that prevail in Ontario, Case 1 system yields lower financial returns than in B.C. if mills in both provinces are able to obtain 5 cents per kWh for their power. On the other hand, the other 3 cases, which have some degree of woodwaste firing, show improved returns relative to B.C., given the higher value of the natural gas which is displaced. In fact, Case 3 provides a slightly higher rate of return than Case 1.

The $5/Odt woodwaste disposal credit is most beneficial to Case 2, given the greater amount displaced by this option. The rate of return for Case 3 also increases substantially, to about 29 percent, increasing its margin over Case 1 to about 5 percent.

3.3.3 Sensitivity to Natural Gas Price Increases

Results for the gas-fired cases are relatively insensitive to changes in rate of natural gas price escalation. For example, in B.C. the higher and lower gas price scenarios would change the rate of return by about 2.5 percent, even in Case 1 where natural gas is the sole fuel. Case 2 results are only slightly more sensitive to gas price increases, even with the larger amount of natural gas displaced. For example, in the Ontario Case 2 results without the woodwaste disposal credit, the IRR increases from 13.2 percent in the base natural gas price escalation scenario, to 17.4 percent in the high price scenario.

4.0 CONCLUSIONS

4.1 Viability of System Configurations

The foregoing analysis clearly shows that at the scale of electrical generation considered, the configuration of the system that relies on straight wood-firing (Case 2) is the least attractive of the four cases. This results from the de-rated power and heat output relative to other cases considered, combined with high capital costs. Straight wood-fired cogeneration may still be valid, particularly at larger scales, but for the indirectly-fired gas turbine system considered herein, there are some potential technical, cost, and size problems with the high temperature heat exchanger which is the crucial component of the system. Configurations of the system which are wholly or partially gas-fired have the potential to overcome the foregoing types of problems to varying degrees.

Conclusions as to the relative merits of the cases which utilize some degree of gas firing vary among regions, depending upon relative natural gas and electricity prices. In British Columbia, Case 1, the straight gas-fired system, is shown to offer the most attractive IRR even if woodwaste-fired systems are assigned a woodwaste disposal credit of $5/Odt. Case 3, which utilizes 27 percent gas firing, ranks as a somewhat distant second to Case 1 in B.C. Aside from providing a higher IRR in B.C., Case 1 offers several other advantages, including:

* much less technical risk than the wood-fired options, as it eliminates the high-temperature heat exchanger. Gas turbine units can be purchased as turnkey units, unlike the wood-fired configurations which require many custom-fabricated components.

* much lower capital cost than any of the other systems, decreasing the financial risk.

* much more compact design, as the bulky heat exchanger and woodwaste handling, storage, and burner systems are not required. Many existing millsites may not be able to easily accommodate the wood-fired configurations of the cogeneration system.

In Ontario, Case 3 is shown to be yield a similar IRR to Case 1 without a $5/Odt woodwaste disposal credit, and a significantly higher IRR with such a credit. If the higher natural gas price scenario were to materialize, Case 3 would provide a much higher IRR than Case 1.

The Case 3 configuration, which is about 73 percent woodwaste-fired, is clearly superior to the Case 4 option in all of the scenarios examined. It offers several operational advantages over the Case 2 option, including the availability of a natural gas combustor for start-up and operation on natural gas when the wood handling or firing systems are down for maintenance. At the same time, it offers increased power and by-product heat output relative to Case 2.

While Case 4 shows less attractive financial returns that Case 3, it does offer several advantages: somewhat lower capital costs, a substantially more compact heat exchanger, along with less technical risk. The latter advantage relates to the lower heat exchanger exit temperature in Case 4.

In summary, it appears that at the scales considered herein, the Case 3 option offers the most potential in the Ontario context, while the Case 1 option would be a more logical choice in British Columbia.

4.2 Viability of Larger Scale System

If the system were scaled up to 2 or 3 MW, the economics of Case 2 would likely improve relative to Case 1 for several reasons. First, as shown in the Phase II report, there appears to be considerable potential for economies of scale with wood-fired systems, particularly in the fuel handling and conveying. Second, gas-fired systems must utilize nearly all of their available waste heat for kiln drying (or space heating) in order to be viable. In a sawmill of the scale considered in the Phase II report (100 million board feet of lumber production annually), the average kiln-drying requirement would be about 20 GJ/hour, versus 14.4 GJ available from by-product heat in Case I. If the system were scaled up to the typical average demand of about 2 MW for a mill of this size, there would be a surplus of heat. As the heat surplus heat increases, natural gas-fired systems obviously are at an increasing disadvantage to a straight woodwaste-fired system for which the fuel is free or even has a negative cost.

4.3 Policy Environment for Cogeneration

Since Phase I of this project was started in 1986, the policies of Canadian electrical utilities towards independent power producers have generally become much more favourable. Electrical and natural gas utilities have the

potential to influence the financial feasibility of industrial cogeneration in several ways. The most direct means is through the price that electrical utilities are willing to pay independent power producers for their power. Ontario and Alberta, for example, have rates in the order of 5 cents per kilowatt hour for small power producers, although in B.C. such producers (less than 5 MW) would only be paid 3 cents per kwh under present policies.

A second way, as discussed in Section 3.2.2, is through changes in the future rate structures of electrical utilities. If the present declining block rate structure is inverted, the incentive for sawmills and other industrial plants to cogenerate could be considerably enhanced. B.C. Hydro will file an application for a restructuring of its present tariff by December 1, 1990.

A third means for utilities to encourage independent power production is to finance the capital costs of cogeneration plants in cases where such costs are lower than their own avoided marginal costs for incremental generation capacity. This has already been done in B.C. where B.C. Hydro has provided 5-year interest-free financing for a large 85 MW cogeneration plant at Canfor's Port Mellon pulp and paper mill. Natural gas utilities, as well as electrical utilities, would logically have an interest in financing cogeneration plants which are partially or wholly natural gas-fired. The ability of utilities to finance projects over longer terms and to accept lower hurdle rates than industrial establishments could result in more industrial cogeneration than if financed by the industries themselves. Utilities, however, may not be willing to undertake this role for small (less than 5 MW) power producers, given the high administrative cost relative to the limited quantity of power produced.

Aside from utility policies with respect to independent power producers, Federal and Provincial government policies will also play an important role in influencing the viability of the cogeneration systems considered in this project. In British Columbia, for example, a policy has recently been implemented to allow for a price premium of up to 15 percent to be paid in the case of independent power projects deemed to be environmentally beneficial. Alternatively, a woodwaste disposal credit of the magnitude considered ($5/Odt), or even higher, could be paid to a plant of this type, significantly enhancing its financial feasibility. A combination carrot-and-stick approach comprising strict enforcement of more rigorous air and water quality standards for woodwaste disposal methods, along with tax credits for a clean-burning system of this type would encourage development of the large untapped woodwaste-fired cogeneration potential that exists in Canada.

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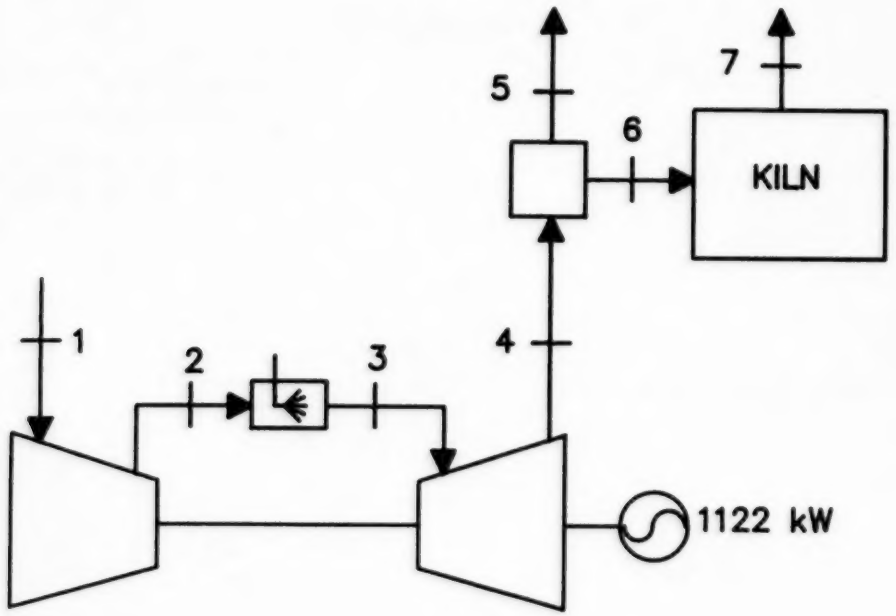
APPENDIX A

WOOD-WASTE COGENERATION - PHASE III - HEAT BALANCE DIAGRAMS

DWG. NO

CASE 1 - STRAIGHT GAS FIRING	A-1
CASE 2 - STRAIGHT WOODWASTE FIRING	A-2
CASE 3 - WOODWASTE WITH 27% GAS CO-FIRING	A-3
CASE 4 - WOODWASTE WITH 50% GAS CO-FIRING	A-4

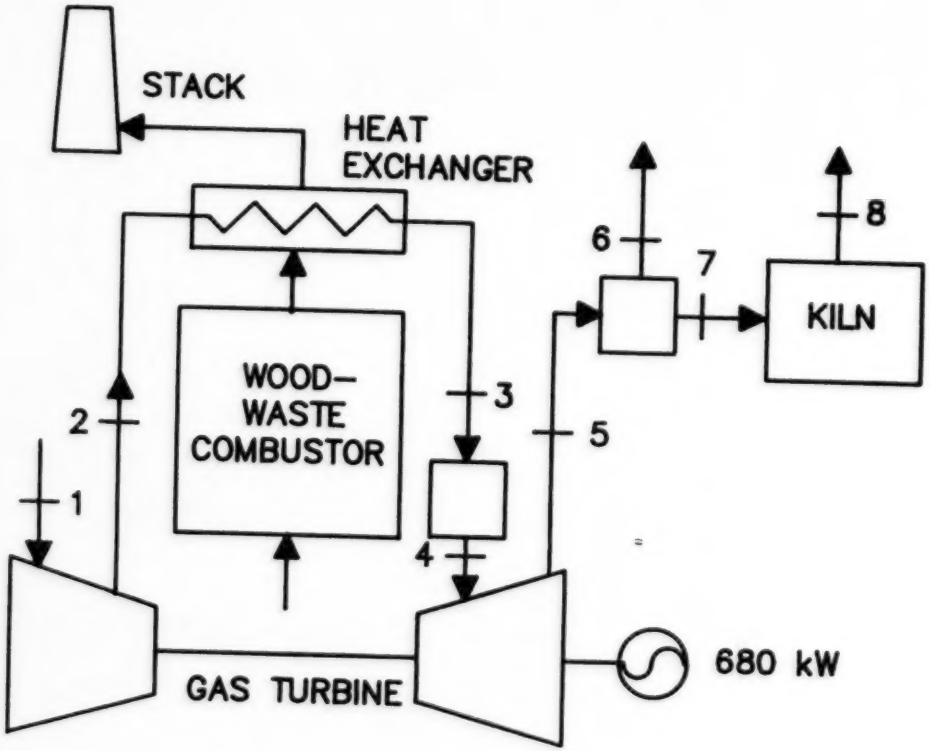


FLOW DATA				
PT.	TEMP. °C	PRESS. kPa	MASS FLOW kg/s	ENERGY FLOW kW
1	15	101	7.7	0
2	308	808	7.7	2302
3	900	808	7.83	7493
4	504	101	7.83	4009
5	–	–	–	–
6	504	101	7.83	4009

CASE 1

STRAIGHT GAS FIRING

R.L. EVANS & ASSOCIATES LTD.
2623 LAWSON AVE., WEST VANCOUVER, B.C.
WOOD–WASTE COGENERATION – PHASE III
HEAT BALANCE DIAGRAM
CASE: 1 – STRAIGHT GAS
DWG. No. A–1 DEC., 1989



FLOW DATA				
PT.	TEMP. °C	PRESS. kPa	MASS FLOW kg/s	ENERGY FLOW kW
1	15	101	7.7	0
2	308	808	7.7	2302
3	760	808	7.7	6114
4	760	808	7.7	6114
5	405	101	7.7	3095
6	–	–	–	–
7	405	101	7.7	3095
8				

CASE 2

STRAIGHT WOODWASTE FIRING

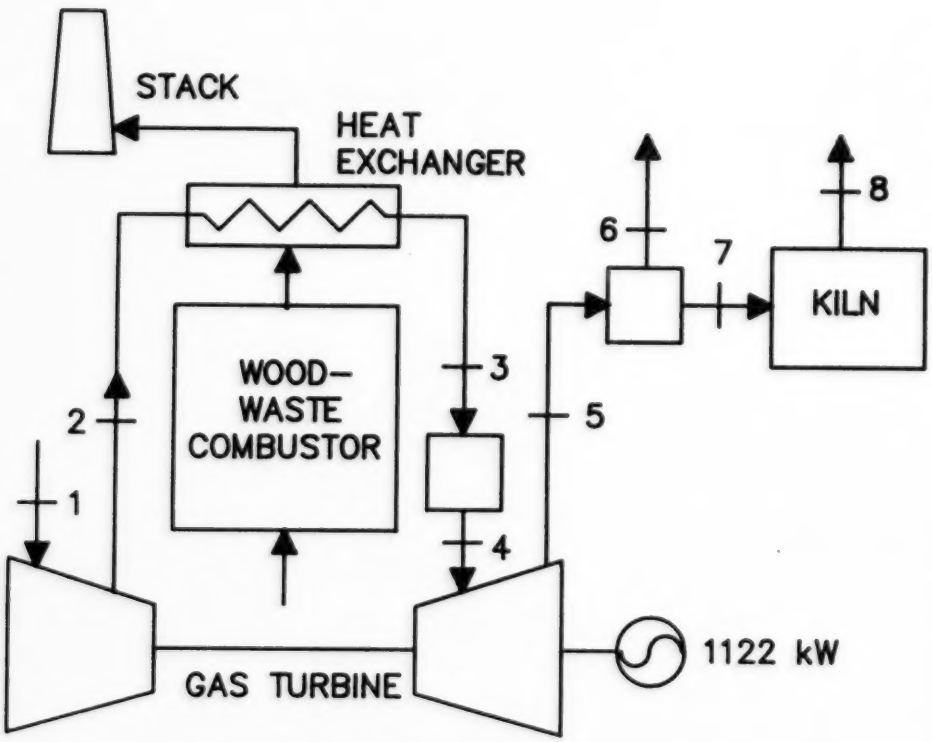
R.L. EVANS & ASSOCIATES LTD.
2823 LAWSON AVE., WEST VANCOUVER, B.C.

WOOD–WASTE COGENERATION – PHASE III

HEAT BALANCE DIAGRAM

CASE: 2

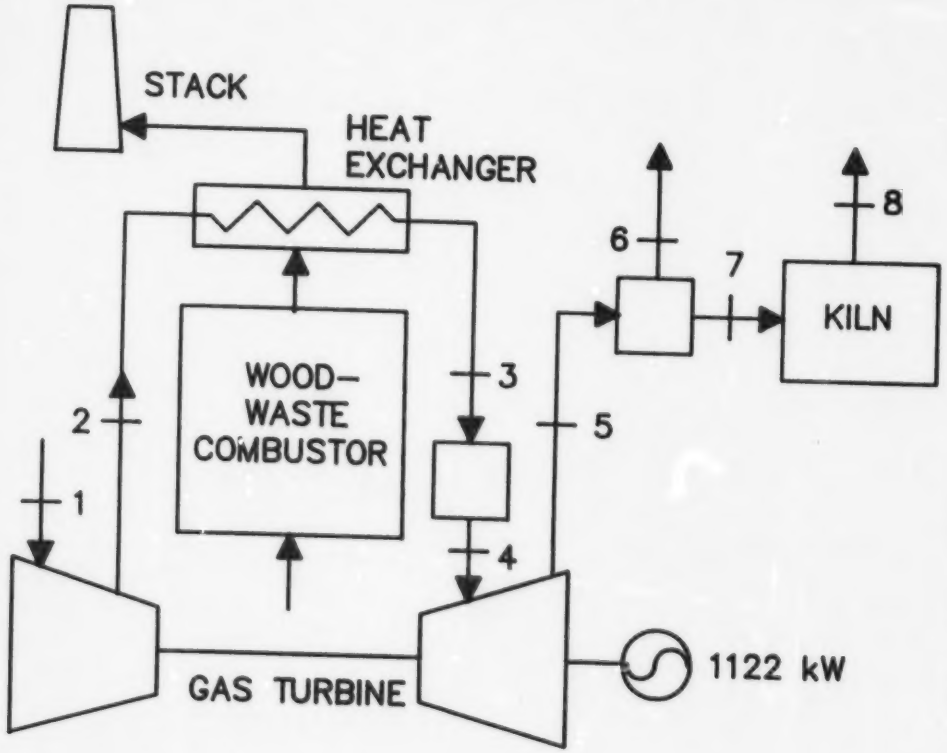
DWG No.: A–2 DEC., 1989



FLOW DATA				
PT.	TEMP. °C	PRESS. kPa	MASS FLOW kg/s	ENERGY FLOW kW
1	15	101	7.7	0
2	308	808	7.7	2302
3	760	808	7.7	6114
4	900	808	7.8	7464
5	504	101	7.8	3993
6	–	–	–	–
7	504	101	7.8	3993
8				

CASE 3
WOODWASTE WITH 27% GAS CO-FIRING

R.L. EVANS & ASSOCIATES LTD.
2623 LAWSON AVE., WEST VANCOUVER, B.C.
WOOD–WASTE COGENERATION – PHASE III
HEAT BALANCE DIAGRAM
CASE: 3
DWG No.: A–3 DEC., 1989



FLOW DATA				
PT.	TEMP. °C	PRESS. kPa	MASS FLOW kg/s	ENERGY FLOW kW
1	15	101	7.7	0
2	308	806	7.7	2302
3	620	806	7.7	4904
4	900	806	7.8	7464
5	504	101	7.8	3993
6	–	–	–	–
7	504	101	7.8	3993
8				

CASE 4
WOODWASTE WITH 50% GAS CO-FIRING

R.L. EVANS & ASSOCIATES LTD.
2623 LAWSON AVE., WEST VANCOUVER, B.C.

WOOD–WASTE COGENERATION – PHASE III

HEAT BALANCE DIAGRAM

CASE: 4

DWG No.: A–4 DEC., 1989

APPENDIX B

CONTRACT DIRECTORY INFORMATION

TITLE: Woodwaste-Fuelled, Indirectly-fired Gas Turbine Cogeneration Plant For Sawmill Applications. Phase III: Preliminary Engineering and Financial Analysis of Alternative Configurations.

CONTRACTOR:

Canadian Resourcecon Limited
2011 - 1177 West Hastings St.
Vancouver, B.C.
V6E 2K3

SCIENTIFIC AUTHORITY

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EMR Canada
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PRINCIPAL INVESTIGATORS:

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M.S. Sinclair (604) 682-8691

CONTRACT NO. 57SZ-23283-8-6058

DURATION: Aug. 1988 to Dec. 1989 COST: $36,000

OBJECTIVE: To examine alternative configurations of a woodwaste-fuelled, indirectly-fired gas turbine cogeneration system for sawmill applications. Based on preliminary engineering and financial analysis of alternatives using varying degrees of natural gas co-firing, identify systems which provide optimal technical and financial performance under various operating conditions.

RESULTS: Analysis illustrates the trade-off between higher capital costs and lower operating costs in the case of a straight woodwaste-fired system, versus lower capital costs and higher operating costs in the case of a straight natural gas-fired system, and intermediate cases involving woodwaste and natural gas co-firing.

CONCLUSION: At the small demonstration scale of electrical generation considered, the configuration of the system that relies on straight woodwaste-firing is the least attractive of the four cases examined. Conclusions as to the relative merits of the other three cases which utilize some degree of gas firing vary among regions, depending upon relative natural gas and electricity prices.